UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
www.epa.gov/region8

MAR 14 2018

Ref: 8WP-SUI

Loren Fuller
MCP Operating
121 Lamar Street, Suite 1525
Houston, TX 77010

RE: Underground Injection Control (UIC)
Minor Permit Modifications
WPX Pennington SWD #1 (ND22335-10898)

Dear Ms. Fuller:

The Environmental Protection Agency Region 8 (EPA) has received WPX's February 2, 2018 email requesting changing the tubing size from 3.5" to 4.5" (Revised Appendix A schematic enclosed), performing an acidization job in the injection zone to improve injectivity (Procedure enclosed), and performing a step rate test (SRT) after the tubing change to determine the new maximum allowable injection pressure (MAIP). Once the tubing change has been done, a mechanical integrity test (MIT) shall be performed to ensure the well's integrity. Once the EPA has reviewed and approved the MIT in writing, the well may continue to operate at a maximum injection rate of 415 barrels per hour (bbl/hr). Based on the results of the SRT, the Permittee may request a new MAIP in a separate modification request. The SRT will be performed using both surface and bottom hole (bomb) pressure gauges. If parting pressure is not achieved during the SRT, the maximum pressure achieved during the test will be the new MAIP, even if it is below the formation parting pressure.

In addition to the items mentioned above, the following language is added to Appendix C, which will allow the operator to perform certain work-overs and the SRT, without violating the Permit:

> The Permittee, with prior written approval from the EPA, may exceed the MAIP for certain work-over procedures or to perform step rate tests.

The EPA has reviewed the request and determined that according to the 40 CFR §144.41, these changes meet the Permit modification classification as described therein and determined that a minor modification of this Permit is required. This modification changes the well construction and sets a maximum injection rate limit of 415 bbls/hr. This well currently has an aquifer exemption with an associated cumulative volume limit that is still in effect. Any request to expand the aquifer exemption needs to be made by the operator. This request shall allow adequate time for the EPA to review the request, including time for public comment and responses. Failure to make the request in a timely manner may require the well to be shut-in. There is no guarantee the request will be approved.

As of the date of this letter, the EPA modifies the following well under the terms and conditions of its respective permit.

Modification Number	Well Name	UIC Permit Number
Minor Modification #1	Pennington	ND22335-10898

Please note the EPA Permit referenced above remains fully effective and enforceable and all other provisions and conditions of the Permit remain as issued or modified.

Sincerely,

Darcy O'Connor
Assistant Regional Administrator
Office of Water Protection

Enclosures: Revised well schematic (Appendix A of Permit)
Well stimulation procedure
Revised Appendix C of the Permit

cc: Edmund Baker
Environmental Director
Three Affiliated Tribes

Elgin Crows Breast
Tribal Historic Preservation Officer
Three Affiliated Tribes

Kenny Lyson
Deputy Director, Energy Division
Three Affiliated Tribes

Revised Appendix A Well Schematic - Minor modification March, 2018

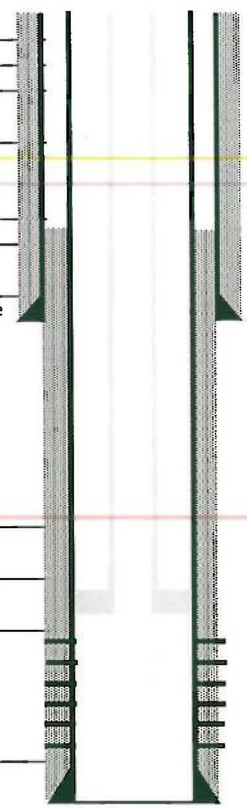
WPX Energy
Pennington SWD #1
Section 2 - T150N - R92W
Montrail County, North Dakota

Wellbore Diagram

WPXENERGY

Log Information

Formation	Top
	70-104'
Sanish/White Shield	149-185'
Tongue River	194'
Slope/Cannonball/ Ludlow	604'
Hell Creek	1,205'
Fox Hills	1,477'
Pierre Shale	1,649'
Greenhorn Shale	4,030
Mowry Shale	4,427'
Dakota/Inyan Kara	4,758
Swift	5,204'



WPXENERGY

WPX Energy Williston Basin

SWD Workover

<u>PENNINGTON 1SWD</u>

<u>Christopher Collard 701-713-0413</u> – 1/9/2018

Section: **2** *Township:* **150** *Range:* **92**

Latitude: **47.844668** *Longitude:* **-102.408607**

Well Information:

Spud Date: ***1/8/2016*** *Cost Code:* ***MCP AFE***

GL Elevation: ***1945*** *'*

KB: ***13'*** *KB Elevation:* ***1958*** *'* *KOP:* ***Vertical***

Formation: ***Dakota Sands*** *Top Perforation: 4797 '*

MD: ***5415*** *'* *Bottom Perforation:* ***5203*** *'*

TVD: ***5414*** *'*

Casing Information: 7" J-55, 23#

To help meet estimated production requirements, the injection capacity of the Pennington Salt Water Disposal well must increase. This capacity is dependent on three separate pressure dynamics: Sand face, Surface, and loss to tubing friction. An acid matrix stimulation will be performed through the 3.5" tubing and KLX packer. The 3.5" lined tubing will then be replaced with 4.5" lined EUE tubing. A Mechanical Integrity Test will be required as the tubing was replaced. To increase the MAIP (Maximum Allowable Injection Pressure) a step-rate test will be performed. The test has been designed with an estimated max rate of 20,000 bbl/d injection.

If you have a spill on location, **immediately** call your supervisor, the production group, and the environmental group; **<u>Bob Raup –701-310-5194)</u>**.

If you have a safety related incident (First Aid, Injury, Property Damage, Fire, Motor Vehicle Accident, etc.) on location, **immediately** call your supervisor, the production group, and the safety group **<u>(Teresa Van Deusen: (701) 500-2619)</u>**.

Acid Stimulation

1) Safety Meeting
    a. Discuss appropriate hazards and plan for the day.
    b. Confirm shutdown of supply pump. Confirm proper "Lock out, Tag out" of pump power systems.
    c. If necessary, perform teardown of pump building to provide proper access to contractor.
2) Coordinate with BJ Services onsite representative for matrix acid stimulation

    Estimated MAX treatment pressure is 1912 psi. This is above MAIP and EPA must provide permission to exceed.

    a) Ensure a safety meeting is held will all personnel and crews on location. Discuss common and special hazards for the job. Discuss plan for the day.
    b) RU pump and treatment equipment.
    c) Proceed with the following pump schedule:

Pennington Acid Stimulation Pump Schedule							
			Clean Fluid at Surface				
Series Number	Fluid	Placement	Rate (bpm)	Vol. (gal)	Cum. (gal)	STP (psi)	Stage Pump Time (min)
1	100 gal Xylene Flush	Flush	3	100	100	1911.83	0.79
2	500 gal 15% HCL Pickle + Xylene	Acid	1.5	500	600	1697.72	7.94
3	Salt Water	Flush	5	3050	3650	1909.91	14.52
4	3000 gal 15% Matrix Acid	Acid	3	3000	6650	1753.19	23.81
5	750 gal Rock Salt Diverter	Pad	4.5	750	7400	1665.15	3.97
6	3000 gal 15% Matrix Acid	Acid	3	3000	10400	1753.19	23.81
7	750 gal Rock Salt Diverter	Pad	4.5	750	11150	1665.15	3.97
8	4500 gal 15% Matrix Acid	Acid	3	4500	15650	1753.19	35.71
9	100 gal Xylene Flush	Flush	3	100	15750	1911.83	0.79
10	Salt Water	Flush	5	3050	18800	1909.91	14.52

3) Record all pump rates and pressures and record in OpenWells.
4) Reconnect all supply lines and gauges. Coordinate with production team to return well to injection promptly. Well must not be allowed to sit static overnight.
5) Reassemble building to prevent freezing of wellhead.

6) Return well to injection. Confirm injection with production team.

Tubing Replacement

1) MIRU: Ensure well is dead. Do not pump fluid without first contacting me.
2) ND wellhead, NU 5K BOP (Size BOP for both 3.5" and 4.5" tubing). Pressure test BOP
3) MU 10" x 3.5" tubing pup joint to tubing hanger. PU and set slips. Remove hanger rotate left to disengage tubing On-Off tool. POOH with 3.5" TK-70 Lined EUE tubing (143 joints), Profile Nipple, 1 joint tubing, and "On-Off" tool.

	Type of Section	Component type	No. of Joints	Length (usft)	Max OD (in)	Top set (usft)	MD base (usft)	Grade	Manufacturer
1	Wellbore Equipment	Tubing Hanger	1	0.00	7.000	13.0	13.0		Cameron
2	Tubing	Tubing	143	4,653.18	4.500	13.0	4,666.2		
3	Wellbore Equipment	Profile Nipple	1	1.14	4.500	4,666.2	4,667.3		KLX
4	Tubing	Tubing	1	32.58	4.500	4,667.3	4,699.9		
5	Wellbore Equipment	On-Off Tool	1	1.75	5.875	4,699.9	4,701.6		KLX
6	Wellbore Equipment	Seating Nipple	1	1.40	3.720	4,701.7	4,703.0		KLX
7	Packer	Packer	1	7.98	5.875	4,703.0	4,711.0		KLX
8	Wellbore Equipment	Profile Nipple	1	1.14	4.500	4,711.0	4,712.2		KLX
9	Wellbore Equipment	Wireline Re-entry	1	0.52	4.500	4,712.2	4,712.7		KLX

Figure 1: Tubing Assy. Please note that tubing OD is 3.5"

4) Change out rams and rig equipment to run 4.5" tubing. PU 1 joint and MU hanger. PT BOP with new rams.
5) RIH with new T-2 On-Off tool, 3.5" to 4.5 crossover single 4.5" tubing joint profile nipple, and the rest of the 4.5" TK-70 lined EUE tubing.
6) Attach to packer via the On-Off tool:
   a. RIH until weight indication shows contact with packer. Work tubing 6-8" pulling up periodically until picking up load to verify good connection. Do not rotate to the right and risk disengaging the packer.
   b. Land tubing hanger at ~20K lbs.
   c. Fill annular volume with packer fluid
      i. Minimal volume is likely

ii. Use freshwater with following chemicals per 100 bbls:
    1. 30 gal MX 879-6 Corrosion w/ scale package
    2. 2 gal B-8632 Biocide
    3. 1 gal SS-5075

iii. Chemical is available on the STAG pad. Record volume used in OpenWells.

7) Proceed to MIT; annular and tubing fluid must remain in well 12-24 hours before performing MIT.

Mechanical Integrity Test

1) Contact EPA field office to determine if field inspector must be present (as early as possible).
    a. Contact Region 8 UIC Offices at 1-800-227-8917
2) Drop plug/SV (consultant preference).
3) Install tubing gauges and recording device
4) Pump filtered produced water to pressure up tubing.
    a. Pressure to 1500 psi
    b. Immediately disconnect from pump and start test time. Hold pressure for 30 min. Monitor and record pressure every 5 min.
    c. Good test if less than 150 psi loss.
5) Run sand line and retrieve plug/SV.
6) Install casing gauges and recording device
7) Pump fresh water to pressure up casing
    a. Pressure to 1500 psi
    b. Immediately disconnect from pump and start test time. Hold pressure for 30 min. Monitor and record pressure every 5 min.
    c. Good test if less than 150 psi pressure loss.
8) Have all paper results delivered to Killdeer office. Email digital results to Christopher.collard@wpxenergy.com.
9) In the absence of an on-site EPA inspector, results must be recorded on the attached form (Tubing/Casing Annulus Pressure Test) and attached to a pressure recording chart. Volume bled back after test should also be recorded on the form.

10) Check with inspector on test. Clean up location.

Step-Rate Test

1) Contact EPA field office to determine if field inspector must be present (as early as possible).
   a. Contact Region 8 UIC Offices at 1-800-227-8917
2) RU pressure testing equipment and horsepower. Retain adequate trucking and determine required fluid volume and availability at MCP.
3) Ensure well pressure is static. Well should be shut in long enough so that pressure is constant.
4) Each step will last 30 min as the anticipated permeability of the Dakota Sands is >10 md.
5) Injection rates must be controlled and regulated. Ensure flowmeter is calibrated.
6) RU wireline
   a. RIH with downhole memory gauge. Set at first profile nipple.
   b. POOH with wireline.
7) Use produced water to conduct SRT according to the following schedule. Record surface pressures every 5 min in addition to downhole gauge.

Step - Rate Test	
% of Max Anticipated Rate	Rate (bbl/min)
5	0.75
10	1.5
20	3
40	6
60	9
80	12
100	15
30 Min Per Step	

8) Estimated fracture gradient is 0.8 psi/ft and center of perforations is 5000 ft. TVD. Breakdown pressure is estimated to be 4000 psi downhole pressure. If breakdown does occur (see attached surface to downhole correction chart), record the ISIP (Instantaneous Shut-In Pressure).
9) Test is concluded once breakdown and ISIP is recorded or max rate is achieved without breakdown. In the case where breakdown does not occur. Call to determine if a higher rate should be tested.
10) RD pressure testing equipment; retrieve pressure gauge via slickline and collect data.

11) Prepare the attached form (Step Rate Test Data) and plot injection rates against stabilized pressure values.
12) Check with inspector on test. Clean up location. RDMO

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION RATE:

Maximum Allowable Injection Rate as measured at the surface shall not exceed the 415 barrels/ hour.

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below. The Permittee, with prior written approval from the EPA, may exceed the MAIP for certain work over procedures and to perform step rate tests.

WELL NAME	MAXIMUM ALLOWED INJECTION PRESSURE (psi) ZONE 1 (Upper)
Pennington SWD #1	1,233

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

WELL NAME: Pennington SWD #1

FORMATION NAME	APPROVED INJECTION INTERVAL (GL, ft) TOP - BOTTOM	FRACTURE GRADIENT (psi/ft)
Dakota - Inyan Kara	4,779.00 - 5,200.00	0.800

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

The cumulative injection volume into the Pennington #1SWD well shall not exceed 59,900,000 barrels. This volume is based on using the perforated interval thickness of 273 feet, a porosity of 22.5% within the injection zone and applying a radius of 1,320 feet. The maximum volume to be used above is more conservative and appropriate than using the net sand thickness calculation that is discussed in the Aquifer Exemption ROD.

In the event this cumulative volume limit is reached, the well shall be shut in and the Director shall be notified. Injection shall not be resumed until Permittee has requested, and the EPA has granted, an expansion of the exempted portion of the Inyan Kara Formation and modified the cumulative injection volume limit in this Permit.